4.6 HAZARDS AND PUBLIC SAFETY

This section describes pipeline hazards and public safety associated with the transport of natural gas by pipeline. The discussion analyzes the probability of upset conditions, the consequences, and contingency measures to reduce either the probability of occurrence or the consequences for the proposed Project.

4.6.1 Environmental Setting

The transportation of natural gas by pipeline involves some risk to the public in the event of an accident and subsequent release of gas. The greatest potential hazard is an explosion within an enclosed space or fire following a major rupture in the pipeline.

Methane, the primary component of natural gas, is colorless, odorless, and tasteless. It is not toxic but is classified as a simple asphyxiant, posing a slight inhalation hazard. If inhaled in high concentration, oxygen deficiency can occur, resulting in serious injury or death.

Methane has an auto-ignition temperature of 1,166 ^{o}F and is flammable at concentrations between 5 and 15 percent by volume in air. Flammable concentrations of methane within an enclosed space in the presence of an ignition source can explode. Methane is buoyant at atmospheric temperatures and disperses rapidly in air; as such, unconfined mixtures of methane in air are flammable but rarely explosive.

The pipeline and the aboveground facilities would be designed, constructed, operated, and maintained in accordance with or exceeding USDOT Minimum Federal Safety Standards in 49 CFR Part 192. These regulations are intended to protect the public and to prevent natural gas facility accidents and failures. They include specifications for material selection and qualification, pipe wall thickness, design pressures, hydrostatic test pressures, MAOP, inspection and testing of welds, and frequency of pipeline patrols and leak surveys (see Section 4.6.4, Impact Analysis and Mitigation).

Under a Memorandum of Understanding (MOU) on Natural Gas Transportation Facilities dated January 15, 1993, between the USDOT and the FERC, the USDOT has the exclusive authority to promulgate Federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of the FERC's regulations requires that an Applicant certify that it would design, install, inspect, test, construct, operate, replace, and maintain the facility for which a Certificate is requested in accordance with Federal safety standards and plans for maintenance and inspection, or certify that it has been granted a waiver of the requirements of the safety standards by the USDOT in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act (NGPSA). The BLM and FERC accept this certification and do not impose additional safety standards. The CSLC may impose more stringent safety standards if so indicated by the results of the CEQA impact analysis.

The standards in the Federal regulations become more stringent as human population density increases near a pipeline. Part 192 also defines area classification, based on population density in the vicinity of the pipeline, that correspond to the minimum safety requirements. The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as follows:

- Class 1 – location with 10 or fewer buildings per mile intended for human occupancy;

- Class 2 – location with more than 10 but fewer then 46 buildings per mile intended for human occupancy;

- Class 3 – location with 46 or more buildings per mile intended for human occupation or where the pipeline lies within 100 yards of any building or small well-defined outside area occupied by 20 or more people during normal use; and

- Class 4 – location where buildings with four or more stories aboveground are prevalent per mile.

Class locations representing more populated areas require higher safety factors in pipeline design, testing, and operation. Figure 4.6-1 depicts the class locations along the ROW. Class locations also specify the maximum spacing allowed for sectionalizing block valves. Part 192 regulations require at least one sectionalizing block location every 20 miles in Class 1 locations, every 15 miles in Class 2 locations, every 8 miles in Class 3 locations, and every 5 miles in Class 4 locations. The spacing for Line 1903 meets these requirements.

Table 4.6-1 summarizes the number of structures in proximity to the pipeline, by milepost. The table also includes the locations of automatic shutdown valves near populated areas. Ninety-five percent of Line 1903 crosses sparsely populated, 1 locations. This equals 288.5 miles of the 303.5 mile line. There are 14 miles of Class 2 locations and one mile of Class 3 locations along the ROW. Class 2 locations are as follows:

- MP 24 to MP 27
- MP 32 to MP 37
- MP 42 to MP 43
- MP 74 to MP 75
- MP 118 to MP 122

Class 3 locations are from MP 43 to MP 44.

Figure 4.6-1 depicts the different class designations and existing land uses for Line 1903. All of the Class 2 and 3 areas are west of the Mojave/Kern Common Facilities at Daggett (MP 132.1). As such, the MAOP of the pipeline from Daggett to Wheeler Ridge is rated at 655 psig, but the pipeline is rated at 944 psig and 1,080 psig through the Class 1 area from Daggett to Ehrenberg (MP 132.1 to MP 303.5).

The existing EPNG pipeline is operated from a centralized Gas Control Center in Colorado Springs, Colorado. These systems are operated and monitored by trained gas control employees 24 hours per day. They constantly monitor the pipeline pressures, flow conditions, and operating conditions of the compressor and meter stations throughout the entire system. The proposed pipeline would also be operated from this Gas Control Center. Section 4.6.4, Impact Analysis and Mitigation, describes the existing safety measures on Line 1903 in greater detail.

Table 4.6-1. Mainline Valve Summary with Population Data

Valve No.	Location (M.P.)	Actuation	Response Time	M.P.	Number of Buildings 0- 200 ft.	200-400 ft.	400-600 ft.	Total Buildings 0 to 660 ft.	Hazard Class[1]
Line 1903									
1	303.5	Manual M/L & Remote M.S.	10 Min.	300-301		2		2	1
				297-298	1	1		2	1
				296-297		2	1	3	1
				295-296	1			1	1
				293-294		1		1	1
				292-293			1	1	1
2	286.3	Manual	1 Hr.					0	1
3	267.0	Manual	1.5 Hr.					0	1
4	247.6	Manual	1.5 Hr.					0	1
5	228.0	Manual	2 Hr.					0	1
6	215.75	Manual	2.5 Hr	215-216			3	3	1
7	215.75	Manual	2.5 Hr.	199-200		3	1	4	1
8	196.57	Manual	2 Hr.					0	1
9	176.57	Manual	1.5 Hr.					0	1
10	156.57	Manual	1.5 Hr.	142-143		1		1	1
				141-142			5	5	1
				139-140		2	5	7	1
				137-138		4	4	8	1
				136-137			4	4	1
11	136.57	Manual	1 Hr.	136				0	1
12	132.1	Manual M/L & Remote M.S.	10 Min.					0	1
13	132.1	Automatic M/L & Remote M.S.	10 Min.	129-130	1			1	1
				128-129		1	1	2	1
				124-125	2	4		6	1
				123-124	3	4	3	10*	2
				122-123			10	10*	2
13a[2]	124	Automatic	1 Min	121-122	2	3	8	13	2
				120-121	2	18	25	45	2
				119-120	3	5	17	25	2
				118B-119	8	8	17	33	2
				118A-118B		2	2	4	1
				118-118A	8	16	14	38	2
				117-118			3	3	1
14	114[2]	Automatic	1 Min	116-117			2	2	1
				115-116		4	1	5	1
				114-115			5	5	1
				113-114	1	2	3	6	1
				105-106	2	1		3	1

Valve No.	Location (M.P.)	Actuation	Response Time	M.P.	Number of Buildings 0- 200 ft.	200-400 ft.	400-600 ft.	Total Buildings 0 to 660 ft.	Hazard Class[1]
15	98.7	Manual	1 Hr.	91-92	2	1	2	5	1
16	82.7	Manual	1.5 Hr.	75-76	0	7	0	7	1
				74-75	0	8	8	16	2
				72-73	0	0	4	4	1
17	63.06	Manual	1.5 Hr.						1
18	63.06	Manual	2 Hr.	54-55	1	1	0	2	1
19	50.46	Automatic	1 Min.	44-45	2	3	1	6	1
				43-44	15	25	9	49	3
				42-43	2	7	6	15	2
				41-42	4	1	0	5	2*
				38-39		1	0	1	2*
19a	37[2]	Automatic	1 Min	36-37	1	3	8	12	2
				35-36		7	12	19	2
				34-35	2	8	9	19	2
				33-34	2	5	13	20*	2
				32-33	3	3	8	14	2
20	32.36	Automatic	1 Min.	31-32	0	1	0	1	1
				30-31	0	0	4	4	1
				29-30	0	2	6	8	1
				28-29	0	1	1	2	1
				27-28	1	0	0	1	1
				26-27	0	0	14	14	2
20a	26[2]	Automatic	1 Min	25-26	4	7	3	14	2
				24-25	10	10	4	24	2
				23-24	0	3	0	3	1
				32-33	3	3	8	14	2
21	21[2]	Automatic	1 Min.	16-17	0	4	2	6	1
				11-12	2	0	1	3	1
				3-4	1	0	0	1	1
22	2.1	Manual M/L & Remote M.S.	10 Min.	2-3	0	2	2	4	1
				0	1		3	4	1
Cadiz Lateral									
1	6.4	Manual M/L & Remote M.S.	10 Min.	0.0-6.4	0	0	0	0	1
Total					**87**	**194**	**255**	**536**	

Notes:
[1] All areas not show in table have no houses within the impact area of the Project and are Class 1 areas.
[2] Proposed modification by CSLC.
*Presently Class 1. Growth planned in near future would bring area to 2.
Response Time includes time for diagnosing problem, dispatching an employee and driving time.
Automatic shut down valves would fully close within 60 seconds of mainline pressure loss.

Manual valves would have an actuator. Valve closure would be initiated by a human operator at the valve site.
M/L = Main Line.
M.S. = Meter Station.
El Paso has personnel stationed at Bakersfield, CA; Barstow, CA; and Ehrenberg, AZ.

Release Probability

This section uses data from reportable gas pipeline incidents nationwide to evaluate the causes and probability of accidents. Subsequently, EPNG's safety record is examined in detail.

Since February 9, 1970, 49 CFR Part 191 has required all operators of transmission and gathering systems to notify the USDOT of any reportable incident and to submit a report on form F7100.2 within 20 days. Reportable incidents have the following characteristics:

- caused a death or personal injury requiring hospitalization;
- required taking any segment of transmission line out of service;
- resulted in gas ignition;
- caused estimated damage to the property of the operator or others, of a total of $5,000 or more;
- required immediate repair on a transmission line;
- occurred while testing with gas or another medium; or
- in the judgement of the operator was significant, even though it did not meet the above criteria.

Since June 1984, the USDOT requires operators only to report incidents that involve property damage of more than $50,000, injury, death, release of gas, or that are otherwise considered significant by the operator. Table 4.6-2 presents a summary of incident data for the periods from 1970 to 1984 and from 1986 to 2001, owing to the change in reporting requirements. The 14.5-year period from 1970 through June 1984, includes more basic report information than subsequent years, and as such has been subject to detailed analysis as discussed in the following sections (Jones et al. 1986).

Table 4.6-2. Industry Service Incidents by Cause per 1,000 Miles/Year (percentage)

Cause	1970 to 1984	1986 to 2001
Outside forces	0.70 (54%)	0.10 (40%)
Corrosion	0.22 (17%)	0.06 (23%)
Construction or material defect	0.27 (21%)	0.03 (14%)
Other	0.11 (8%)	0.06 (23%)

During the 14.5-year period, 5,862 service incidents were reported over the more than 300,000 total miles of natural gas transmission and gathering systems nationwide. Of the 5,862 incidents, 20 incidents resulted in fatalities, 191 incidents resulted in injuries, and 22 incidents involved both fatalities and injuries. While the total number of incidents works out to more than one incident per day, the total number of deaths in this period was 74, and the total number of injuries was 438—or five deaths and 30 injuries per year during this period. Service incidents, defined as failures that occur during pipeline operation, remained fairly constant over this period with no clear upward or downward trend in annual totals. In addition, 2,013 test failures were reported. Correction of test failures removed defects from the pipeline before operation.

Table 4.6-3 summarizes the most frequent causes of accidents, provided as a percentage distribution of the causal factors, as well as the annual frequency of each factor per 1,000 miles of pipeline in service.

Table 4.6-3. Outside Forces Incidents by Cause (1970 to 1984)

Cause	Percent
Equipment operated by outside party	67.1
Equipment operated by or for operator	7.3
Earth Movement	13.3
Weather	10.8
Other	1.5

The pipelines included in the data set in Table 4.6-3 vary by age, pipe diameter, and level of corrosion control. Each variable influences the incident frequency that may be expected for a specific segment of pipeline.

The dominant incident cause is outside forces, constituting 54 percent of all service incidents between 1970 and 1984. Outside forces include impact by mechanical equipment, such as bulldozers and backhoes; earth movements due to soil settlement, washouts, or geological hazards; weather effects, such as winds, storms, and thermal strains; and willful damage. Table 4.6-3 shows that human error in equipment usage was responsible for about 75 percent of outside force incidents. Since April 1982, operators have been required to participate in One-Call public utility programs in populated areas, to minimize unauthorized excavation activities in the vicinity of pipelines. The One-Call program is a service used by public utilities and some private sector companies, for example, oil pipelines and cable television, to provide pre-construction information to contractors or other maintenance workers on the underground location of pipes, cables, and culverts. In compliance with this regulatory requirement, EPNG would notify the one-call system prior to any earth-disturbing activity, and participate in the system as protection for their own lines. The 1986 through 2001 data in Table 4.6-3, reported under different criteria than for 1970 to 1984, show that the portion of incidents caused by outside forces has decreased to 40 percent.

The frequency of service incidents strongly depends on pipeline age. While pipelines installed since 1950 exhibit a fairly constant level of service incident frequency, pipelines installed before that time have a significantly higher rate, partially due to corrosion. Older pipelines have a higher frequency of corrosion incidents, since corrosion is a time-dependent process. Further, more advanced coatings and cathodic protection to reduce corrosion potential are generally used on newer pipe.

Older pipelines have a higher frequency of outside forces incidents, partly because their location may be less well known and less well marked than newer lines. In addition, the older pipelines contain a disproportionate number of smaller diameter pipelines, which have a greater rate of outside forces incidents. Small-diameter pipelines are more easily crushed or broken by mechanical equipment or earth movements.

Table 4.6-4 clearly demonstrates the effectiveness of corrosion control in reducing the incidence of failures caused by external corrosion. The use of both an external protective coating and a cathodic protection system, required on all pipelines installed after July 1971, significantly reduces the rate of failure compared to unprotected or partially protected pipe. Although the data show that bare, cathodically protected pipe has a higher corrosion rate than unprotected pipe, this observation reflects the retrofitting of cathodic protection to actively corroding spots on pipes. The All American Pipeline was installed in 1988, and is protected from external corrosion by both a protective coating and by a cathodic projection system. The new pipe that would be installed by the Project would also have protective coating and a cathodic protection system.

Table 4.6-4. External Corrosion by Level of Control (1970 to 1984)

Corrosion Control	Incidents per 1,000 miles/year
None – bare pipe	0.42
Cathodic protection only	0.97
Coated only	0.40
Coated and cathodic protection	0.11

Pipeline Accident Data

The service incidents summarized in Table 4.6-2 include pipeline failures of all magnitudes with widely varying consequences. About two-thirds of the incidents were classified as leaks; the remaining one-third were classified as ruptures, implying a more serious failure. Fatalities or injuries occurred in 4 percent of the service incidents reported in the 14.5-year period from 1970 through June 1984.

Table 4.6-5 presents the average annual fatalities that occurred on onshore and offshore natural gas transmission and gathering lines from 1970 to 2001. The data show that the total annual average for the period from 1984 through 2001 was 3.1 fatalities per year for onshore pipeline. The simplified reporting requirements in effect after June 1984 do not differentiate between employees and non-employees.

Table 4.6-5. Annual Average Fatalities – Gas Transmission and Gathering System (1970-2001)

Year	Employees	Non-Employees	Total
1970 to June 1984	2.4	2.6	5.0
1984 to 2001	N/A	N/A	4.1
1984 to 2001	N/A	N/A	3.1[1]

Notes:
1) 1970 through June 1984 – Jones et al. 1986; USDOT Hazardous Materials Information System.
2) Total recalculated to exclude 18 offshore fatalities occurring in 1989 – 11 fatalities resulted from a fishing vessel striking an offshore pipeline, and 7 fatalities resulted from an explosion on an offshore production platform.
N/A = Employee/non-employee breakdown not available after June 1984.

The nationwide totals of accidental fatalities from various manmade and natural hazards as listed in Table 4.6-6 provide a relative measure of the industry-wide safety of natural gas pipelines. Direct comparisons between accident categories should be made cautiously, because individual exposures to hazards are not uniform among categories. Nevertheless, the average of 3.1 public fatalities per year is relatively small considering the more than 311,000 miles of transmission and gathering lines in service nationwide, resulting in an annual risk of fatality by gas transmission and gathering lines of approximately 1×10^{-5}. Deaths by other types of accidents, as illustrated below, are much more frequent.

Table 4.6-6. Annual Nationwide Accidental Deaths

Type of Accident	Fatalities
All accidents and adverse effects (1990, 1995, 1997, 1998 average)	93,525
Motor vehicles (1990, 1994—1998 average)	42,114
Railroad accidents (1990 – 1998 average)	1,158
All liquid and gas pipelines (1986 – 2001 average)	24.6
Gas transmission and gathering lines (1986 – 2001 average)[1]	3.1

Notes:
All data, unless otherwise noted, reflect statistics from the US Department of Commerce, Bureau of the Census, Statistical Abstract of the United States, 118th Edition (Published 1998).
Sources:
USDOT, Office of Pipeline Safety, 2002, http://ops.dot.gov/stats.htm.

EPNG's rate of pipeline incidents is similar to the industry averages summarized in Table 4.6-2. EPNG experienced a significant accident on August 19, 2000 near

Carlsbad, New Mexico. Internal corrosion led to a gas release, and the escaping natural gas ignited, causing an explosion and fire. Twelve people camping and fishing nearby were killed in this event. As a result, the National Transportation Safety Board (NTSB) conducted an extensive review of the accident, and of EPNG's operating practices and procedures. The accident was not attributable to operating practices and procedures. The issue of internal corrosion was not a focus of monitoring prior to the accident, but has since received considerably greater attention. Since the accident, EPNG has implemented a Total Integrity Management System for its pipelines. This system requires complete in-line inspections of pipelines by 2010, active monitoring of gas quality, liquid sampling and testing, and a continuous improvement system focused on sharing best management practices.

4.6.2 Regulatory Setting

Federal

FERC

In considering whether to grant a Certificate of Public Convenience and Necessity, the FERC considers factors such as project engineering and design, existing facilities and service, landowner concerns, and environmental concerns.

49 CFR Part 192

The USDOT is mandated to provide pipeline safety under Title 49 USC Chapter 601. The USDOT Research and Special Programs Administration's (RSPA's) Office of Pipeline Safety (OPS) administers the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. The RSPA develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards, which set the level of safety to be attained and allow the pipeline operator to use various technologies in order to achieve safety. Section 5(a) of the NGPSA provides for a State agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the Federal standards. Section 5(b) of the NGPSA permits a State agency that does not qualify under Section 5(a) to perform certain inspection and monitoring functions. A State also may act as the USDOT's agent to inspect interstate facilities within its boundaries; however, USDOT is responsible for enforcement action. The majority of the states, including California, have either Section 5(a) certifications or Section 5(b) agreements, while nine states act as interstate agents.

USDOT pipeline standards are published in 49 CFR Parts 190-199. 49 CFR Part 192 specifically addresses natural gas pipeline safety issues but does not address issues such as siting and routing. These items, in part, involve private negotiation between pipeline companies and landowners.

The pipeline and aboveground facilities associated with the Project must be designed, constructed, operated, and maintained in accordance with USDOT Minimum Federal Safety Standards in 49 CFR Part 192. These regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. 49 CFR Part 192 specifies material selection and qualification; minimum design requirements; and protection from internal, external, and atmospheric corrosion.

Also, 49 CFR Part 192 defines area classifications, based on population density in the vicinity of the pipeline, and specifies more rigorous safety requirements for populated areas. The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. See Section 4.6.1, Hazards and Public Safety, and Table 4.6-1.

More populated areas require higher safety factors in pipeline design, testing, and operation. Pipelines constructed on land in Class 1 locations must be installed with a minimum cover depth of 30 inches in normal soil and 18 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in soil and 24 inches in consolidated rock.

Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil and 24 inches in consolidated rock. Class locations also specify the maximum distance to a sectionalizing block valve for onshore line segments. Pipe wall thickness and pipeline design pressures, hydrostatic test pressures, MAOP, inspection and testing of welds, and frequency of pipeline patrols and leak surveys must all conform to higher standards in more populated areas. Additional information on operation and maintenance procedures applicable to the proposed pipeline, including inspection procedures, is provided in 49 CFR Subparts L and M.

In addition to the class system that determines pipeline design standards, USDOT has developed a criterion for identifying High Consequence Areas (HCAs), in Part 192.761. For the Project 30-inch diameter pipeline and MAOP greater than 1,000 psig, HCAs include Class 3 and Class 4 segments plus identified sites within 1,000 feet of the centerline of each pipeline. Identified sites include facilities where mobility-impaired people may be present or public gathering areas. Facilities where mobility-impaired people may be present include, but are not limited to, day-care, retirement, educational, and assisted living facilities. Public gathering areas are buildings or outdoor areas where at least 20 people gather at least 50 days within any 12-month period. Examples include, but are not limited to, beaches, playgrounds, recreational facilities, outdoor theaters, and religious facilities.

49 CFR Part 192 prescribes the minimum standards for operating and maintaining pipeline facilities, including the requirement to establish a written plan governing these activities. Under Section 192.615, each pipeline operator also must establish an emergency plan that includes procedures to minimize the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for:

- receiving, identifying, and classifying emergency events, gas leaks, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials, as well as coordinating emergency response;
- making personnel, equipment, tools, and materials available at the scene of an emergency;
- protecting people first and then property, and making them safe from actual or potential hazards; and
- implementing emergency shutdown of the system and safely restoring service.

49 CFR Part 192 requires each operator to establish and maintain a liaison with the appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency, and to coordinate mutual assistance. EPNG would implement a public liaison program for its new facilities. EPNG must establish a continuing education program to enable

customers, the public, government officials, and those engaged in excavation activities to recognize a gas pipeline emergency and report it to appropriate public officials.

State

As part of its leasing process in California, the CSLC reviews pipeline projects to ensure that they are designed in compliance with applicable Federal and California standards, and that they reflect current geologic and seismic information. The CSLC's engineering and environmental review assesses both siting and safety issues, such as the location of the Project relative to seismic and populated areas, and the adequacy of the information contained in the Applicant's construction, operations, maintenance, and emergency response plans. Such issues include proposed internal and external maintenance inspection processes, integrity testing methods to be applied, corrosion monitoring and testing and calibration of the cathodic protection system, leak monitoring, and emergency response plans and procedures. In determining whether to approve a lease or certify the CEQA documentation for a project, the CSLC may consider whether standards above the USDOT minimum standards provided for in 49 CFR Part 192 are warranted in fault zones and populated areas, and may require additional safety measures—such as the installation of automatic shutoff valves in these areas. For approved projects, the CSLC staff also reviews (for consistency with the CSLC's action on the lease) post-construction documentation, including as-built construction plans showing any design changes or other amendments to the Project as approved; pipeline test results, such as smart pig and hydrostatic testing, and details of any extraordinary occurrences, such as spill incidents and accidents.

Local

San Bernardino County has the following requirements for pipelines:

- include the location of the underground pipelines and the type of fuel being carried in the pipelines on the Infrastructure;
- direct staff to prepare a plan for Development Code implementation to improve safety in areas affected by pipelines; and
- designate a staff member to coordinate with the County Department of Transportation Utilities Coordinator, the various pipeline companies, and the

cities with pipelines in their jurisdiction in order to keep accurate, up-to-date records of pipelines activity within the county.

Kern County treats oil pipelines and gas pipelines in the same way.

4.6.3 Significance Criteria

An adverse impact regarding hazards and public safety was considered significant if the Project would:

- expose people to existing or potential hazards, including upset and accident conditions involving the release of hazardous materials into the environment;
- create significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials;
- create hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within 0.25 mile of an existing or proposed school, residential area, or other sensitive receptor;
- impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan; or expose people or structures to a significant risk of loss, injury, or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands; or
- significantly increase fire hazard in areas with flammable materials.

4.6.4 Impact Analysis and Mitigation

Existing Safety Measures

Before construction, EPNG would inspect the pipe to ensure that it meets specifications and quality standards. During construction, the integrity of coating designed to protect against corrosion would be checked and imperfections would be corrected. Welds would be quality checked with x-rays. EPNG would test the pipe with water to a pressure ranging from 125 to 180 percent of the MAOP.

Before placing the pipeline into service, EPNG would perform post-construction smart pig surveys. The device would inspect the entire pipeline for any areas of wall thickness below MAOP limits. The inspection would also locate construction-related dents. The generation of instrumented internal inspection device run through the pipeline would depend on the expected type of defect. Dents would be found with a geometry pig; corrosion would be found with any number of pigs that run in various mediums from natural gas to air to water. Because internal inspection technology continues to evolve, the specific inspection devices that would be used depend on the technology and type of inspection devices available at the time of the inspection.

The upgraded cathodic protection system is required in order to prevent or minimize external corrosion of the buried pipeline. The cathodic protection system would impress a direct current on the pipe, thus providing a ground-bed anode that would corrode instead of the pipeline. The main components of the cathodic protection system would be anode beds, rectifiers, and test stations.

EPNG would clearly mark the pipeline facilities at line-of-sight intervals and at crossings of roads, railroads, and other key points. The markers would clearly indicate the presence of the pipeline and provide a telephone number and address where a company representative may be reached in the event of an emergency or before any excavation in the area of the pipeline by a third party. EPNG participates in all communication and notification services to prevent damage to underground utilities (One-Call systems).

The pipeline system would be inspected by air to observe ROW conditions and identify indications of leaks, evidence of pipeline damage, evidence of encroachment, landowners building permanent structures on the permanent ROW, or damage to erosion controls resulting from erosion or washouts. EPNG currently inspects the pipeline system by air on a bi-weekly basis, weather permitting. This frequency exceeds the USDOT requirement for patrolling, which stipulates that pipeline patrols be conducted at least annually.

EPNG operates numerous safety systems on its existing pipeline system that would also be used on the Line 1903 Project pipeline. The mechanical-type safety controls include relief valves on the outlet of compressor stations, remotely operated main line valves (MLVs) in populated areas, and low-pressure shutdowns on MLVs in populated locations that close when the pressure drops below a certain level. EPNG would equip the MLVs located upstream and downstream of faults crossed with actuators.

Automatic valves would typically close faster than remotely operated valves, which need to be closed from the Gas Control Center. However, automation is limited in many places on EPNG's system due to the remoteness of the MLVs (radio signal cannot access certain MLVs due to mountain ranges and other obstructions to radio signals). If a situation occurs that may require closure of an MLV, a gas control worker in the applicable Gas Control Center would attempt to verify whether a situation exists that may result in impacts on public safety or damage to personal property. This is done to prevent unnecessary closure of an MLV that could be detrimental to customers connected to the pipeline. The gas control worker has the authority to make the decision to close an MLV but may also consult with the Manager of Gas Control, Director of Operations Support, or a local field representative. During normal operation of the pipeline, there is a 2-minute interval between scans on the SCADA system. If an event alarms at the Gas Control Center, the gas control worker can put the individual site(s) on a faster interval scan where the SCADA system scans those sites at a faster rate so that any unfolding events can be quickly analyzed. If the gas control worker determines that it is necessary to close an MLV, a "close" command would be sent to the MLV. The MLV site communication would verify that the command is received, and the gas control worker would send a second "close" command to reconfirm the request. Once the second close command has been received, the MLV would close. The typical time that it takes to close an MLV on a large-diameter pipeline is approximately 2 minutes. The total time from the first close command to the MLV closure can be as little as 3 to 4 minutes

EPNG has in place a policy to ensure that its operations employees identify safety-related (unsafe) conditions and follow company procedures in reporting these conditions to their management. The operations management then confirms the existence of a potential safety-related condition and establishes communication with the pipeline safety manager. EPNG's policy contains flowcharts for evaluating defects to determine what remedial action is required. Examples of defects evaluated with these flow charts include leaks, dents, corrosion, mechanical damage and imperfection, and arc burns. Each step in the flowchart requires personnel to evaluate the defect from an array of criteria. A required course of action is then determined once the flowchart steps are completed.

The first step in EPNG's procedure for the repair or replacement of damaged pipe is to take immediate action to protect the safety of the public and company personnel. Once the work area is safe, qualified EPNG personnel evaluate the pipe to determine whether the pipe is leaking or whether there is coating damage, surface scratching of the pipe, gouging or removed metal, dents, or cracking of the pipe. EPNG personnel evaluate the extent of the defect, taking into account the circumferential as well as overall extent of the defect. The severity and characteristics of the damage are evaluated using several methods, depending on the defect. For example, dye-penetrant material finds cracks that may result from third-party mechanical damage. Third-party damage can also produce dents in the pipe. The dents are measured and, if they exceed certain criteria, they are either repaired or cut out. If corrosion is the cause of the defect, the areas of corrosion are measured and repaired, if necessary. Before making repairs, the pipeline pressure would be reduced, if necessary, to a safe level based on the preliminary determination of the defect. After repairs are performed, the pipe is recoated, backfilled, and placed into operation.

EPNG is required to monitor its entire system once a year for changes in population density. When these changes occur, EPNG is required to ensure that the installed pipeline meets the criteria for pipe design that applies in the higher class location. If it does not meet these requirements, the pipe is replaced, the operating pressure in the line is reduced, or similar safety measures are undertaken by EPNG to achieve the required margin of safety.

Federal law requires EPNG to conduct public education programs. EPNG would provide residents who live along the ROW with information about the pipeline, including what activities to look for and what to do in an emergency. EPNG would provide these residents and emergency response officials with information to educate them about the nature of its operations and the appropriate actions to take if there is an accident.

All of these operation and maintenance procedures are documented in a written plan EPNG developed in accordance with 49 CFR Part 192. EPNG has provided its Operation and Maintenance Plan to the CSLC for engineering review, and it has been accepted for operation of Line 1903.

Under 49 CFR Part 192, Section 192.615, each pipeline operator must also establish an Emergency Response Plan that includes procedures to minimize the hazards in a natural gas pipeline emergency. While EPNG's primary safety focus is accident prevention, EPNG has, in accordance with Part 192, developed an Emergency Response Plan for the proposed Project based on its current plan, which would be coordinated and tested (through drills and exercises) with local fire/police departments and emergency management agencies. This plan would also be reviewed by the USDOT OPS and is subject to USDOT rules and regulations. EPNG has provided its Emergency Response Plan to the CSLC for engineering review. Key elements of the Emergency Response Plan include procedures for:

- receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials, and coordinating emergency response;
- making personnel, equipment, tools, and materials available at the scene of an emergency;
- protecting people first and then property, and making people safe from actual or potential hazards; and
- emergency shutdown of the system and safe restoration of service.

EPNG maintains 24-hour emergency response capabilities, including an emergency-only toll-free telephone number. The number is included in informational mail-outs, posted on all pipeline markers, and provided to local emergency agencies in the vicinity of the pipeline.

EPNG currently meets with the emergency services departments of the municipalities and counties along its existing pipeline facilities. Fire and safety equipment is maintained along the pipeline system, and EPNG personnel and local emergency response groups are trained in response procedures. EPNG personnel consult with local fire departments and emergency response agencies to determine whether additional equipment, training, and preparedness support are needed and to provide additional equipment, training, and support where the needs are identified. EPNG provides these departments with the 24-hour emergency numbers and verbal, written, and mapping descriptions of the pipeline system. EPNG representatives also meet with all local emergency service units on an ongoing basis. These procedures would continue for the EPNG Line 1903 Project.

EPNG would provide the following documents to the CSLC within 120 days of the completion of work in California:

- a set of as-built construction plans, certified by a California-registered civil/structural engineer, showing all design changes or other amendments to the construction as originally approved;

- certified copies of all completed pipeline integrity test results, such as hydrostatic tests and gauging runs, including copies of any failed test results with an explanation of the reason for failure; and

- a post-construction written narrative report confirming completion of the Project, with discussion of any significant field changes or other modifications to the approved design or executive plan; providing details of any extraordinary occurrences, such as reportable accident incidents, and a summary of a quality control and weld inspection program, including all failed and repaired welds.

Consequences of Natural Gas Release

When Line 1903 carried oil as the All American Pipeline, releases had the potential to affect drinking water resources and ecological resources, and cause third-party property damage. In converting from oil to natural gas transport, the types of hazards change.

A rupture and release of natural gas would affect a more limited area and would not pollute drinking water or ecological resources (EPA 2002). A natural gas pipeline rupture could, however, cause an explosion, and the release of natural gas and mixing with air could ignite and cause a fire if there is an ignition source. The consequence of a rupture of the pipeline and release of natural gas was modeled following the protocol established in 49 CFR Part 192 – Pipeline Safety: High Consequence Areas for Gas Transmission Pipelines (EPA 2002). The analysis is based on a model developed by C-FER, a Canadian research and consulting organization. The C-FER analysis considered the complete rupture of a natural gas pipeline rupture. The model included a simplified mathematical treatment of several phenomena important to characterizing the extent of damage following a pipeline rupture, such as critical heat flux, the time of ignition of the escaping gas, the height of the burning jet, and the pipe decompression rate. The model also included estimates of several important parameters associated with the phenomena. The model agreed well with actual data for these parameters.

The method calculates the heat flux (radiation intensity) from a full cut of the pipeline. The impact area is based on acute effects to humans (blistering and mortality) and structures (spontaneous and piloted ignition to wooden structures). Outside the impact area, property would not be expected to ignite and burn, in-door people would be protected indefinitely, and outdoor people would be exposed to a "finite but low chance of fatality."

The worst-case impact area calculated in this way is different for Line 1903 east and west of the Mojave/Kern Common Facilities at Daggett (MP 132.1) because of the change in MAOP. East of Daggett, the impact area is 630 feet on either side of the pipeline, with the exception of the higher MAOP area from MP 215.75 to MP 247.6, which has an impact area of 675 feet. West of Daggett, the impact area is 525 feet on either side of the pipeline. The impact area for the Cadiz Lateral is 675 feet. This impact area is depicted on the resource maps for the pipeline ROW (Appendix A).

Contamination from Leaks or Spills from Construction Equipment

Contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment could adversely affect soils. The potential impact is expected to be minor because of the typically low frequency, volume, and extent of spills or leaks on pipeline construction projects. Implementation of EPNG's SPCC Plan (Appendix D4) would reduce the potential impact of soil contamination from spills or leaks to a less-than-significant level.

Exposure of Contamination by Excavation

During operation as an oil pipeline, several known releases led to soil contamination. Areas of releases that were not detected could exist. Construction activities could expose these contaminated soils, resulting in a threat to human or ecological receptors. EPNG has developed a Contaminated Soils Plan (Appendix D9) for implementation during construction activities. The plan describes testing requirements, significance criteria, and remediation methods to be applied in the event that oil-contaminated soil is encountered. Implementation of this plan would reduce the impact of exposure to contaminated soils to a less-than-significant level.

Impact for HAZ-1: Potential for Gas Line Rupture and Release of Natural Gas

Line 1903 could rupture and release natural gas, potentially causing a fire or explosion. (Potentially Significant, Class I)

The probability analysis indicated that there is a very low likelihood for a high-consequence rupture and release of natural gas during the operation of Line 1903. The annual risk was approximately 1 x 10^{-5} fatalities per mile of pipeline. However, such an event could occur, with the consequences described in Section 4.6.4, Impact Analysis and Mitigation. The concern is greatest in the more highly populated Class 2 and Class 3 locations. Table 4.6-1 summarizes the locations of structures in the potential impact area, and these are depicted in Figure 4.6-1. EPNG's proposed valve locations do not adequately protect these areas.

EPNG's Operation and Maintenance Plan does not include specifications for conducting instrumented internal inspections using a high-resolution device commonly known as a "smart pig." Although not currently required by the OPS, an instrumented internal inspection on a periodic basis with a high-resolution tool is a proactive method of determining the mechanical integrity of a pipeline by obtaining data that show whether corrosion is occurring internally or externally, or if other damage anomalies have occurred along the pipeline as well as verifying that the cathodic protection system is protecting the external wall of the pipeline.

Finally, third-party damage, the most common cause of pipeline rupture, is a concern in an area that is experiencing continued construction.

Mitigation for Impact HAZ-1:

MM HAZ-1a: ***Installation of Shutdown Valves.*** *EPNG would install automatically-actuated shutdown valves upstream and downstream of Class 3 areas (Table 4.6-1 and Figure 4.6-1). These new or moved valve locations enhance safety protection in populated Class 2 and Class 3 areas.*

MM HAZ-1b: ***Revised Operation and Maintenance Plan.*** *60 days prior to placing Line 1903 into service, EPNG would obtain approval from the CSLC for a revised Operation and Maintenance Plan. The revised plan would address internal and external maintenance inspections of the completed facility, including details of integrity testing methods to be applied, corrosion monitoring and testing of the cathodic protection system, and leak monitoring. The plan would also specify that EPNG would, unless expressly prohibited by USDOT regulations, conduct an internal inspection with a high-resolution instrument on a periodic basis, at a minimum of one inspection every 10 years. If the data show that significant corrosion or defects exist, or if any new Federal or State regulations require more frequent or comparable inspections, then the inspection frequency would be increased to once every five years. The revised Operation and Maintenance Plan would also include Post-Earthquake Inspection Monitoring Plan, identified as mitigation measure GEO-1. Within 3 months following the promulgation of any new Federal or State regulations, EPNG would update the plan and submit a revised copy to the CSLC.*

MM HAZ-1c: ***Measures to Reduce Third Party Damage.*** *60 days prior to placing the portion of Line 1903 within a Class 2 or higher area into service, EPNG would obtain approval from CSLC for enhanced protection from third-party damage. EPNG must consider the installation of concrete mats above the pipeline to reduce the potential for pipeline damage, or other measures that provide similar levels of protection.*

Rationale for Mitigation

The mitigation measures address the principal means by which pipeline ruptures and subsequent explosions or fires occur. HAZ-1a reduces the amount of gas released by the installation of automatic shut-down valves. HAZ-1b reduces the likelihood of internal or external corrosion through increased testing of wall thickness. HAZ-1c reduces the likelihood of third-party damage to the pipeline.

Table 4.6-7 presents a summary of impacts on hazards and public safety and recommended mitigation measures.

Table 4.6-7. Summary of Impacts and Mitigation Measures for Hazards and Public Safety

Impact	Mitigation Measure
HAZ-1: Potential for Gas Line Rupture and Release of Natural Gas	**HAZ-1a**. Installation of Shutdown Valves **HAZ-1b.** Revised Operation and Maintenance Plan **HAZ-1c.** Measures to Reduce Third Party Damage

4.6.5 Cumulative Impacts

In addition to the proposed Project, other projects may contribute to cumulative impacts on public safety in the vicinity of the Project. The projects under construction and potentially contributing to cumulative impacts in the vicinity of the Project are discussed in Section 5.5, Summary of Cumulative Impacts.

Line 1903 would connect with existing natural gas infrastructure at Wheeler Ridge, Daggett, Amboy, Ehrenberg, and potentially in the vicinity of Cadiz. Line 1903 would tie-in with the existing Mojave Pipeline at Amboy, the Mojave/Kern Common Facilities at Daggett, the SoCalGas system at Wheeler Ridge, and Line 2000 at Ehrenberg. Additionally, several smaller natural gas pipelines associated with local systems are located within 500 feet of Line 1903. Each of these gas pipelines have the potential for a release of natural gas, and associated explosion of fire. Therefore, the cumulative impact related to hazards would be significant.

4.6.6 Alternatives

No Project Alternative

The No Project Alternative would not convert the former All American crude oil pipeline system to a natural gas transmission system. This alternative initially would not affect hazards or public safety.

Ehrenberg to Daggett Alternative

The Ehrenberg to Daggett Alternative would not construct the portion of Line 1903 from MP 0 to MP 132.1. This alternative would avoid conversion of the pipeline in all areas with sufficient population density to be considered a Class 2 or Class 3 area. Consequently, this alternative would avoid the potentially significant public safety impacts that are associated with the proposed Project by avoiding operation of a natural gas pipeline in a more densely populated area. The mitigation measure HAZ-1b would be required, but the impact would be less than significant (Class II) with mitigation because of the low population density.

Ehrenberg to Cadiz Alternative

The Ehrenberg to Cadiz Alternative would not construct the portion of Line 1903 from MP 0 to MP 215.75. This alternative would avoid conversion of the pipeline in all areas with sufficient population density to be considered a Class 2 or Class 3 area. Consequently, this alternative would avoid the potentially significant public safety impacts that are associated with the proposed Project by avoiding operation of a natural gas pipeline in a more densely populated area. The mitigation measure HAZ-1b would be required, but the impact would be less than significant (Class II) with mitigation.

4.6.7 References

California State Lands Commission and Federal Energy Regulatory Commission. 2002. Kern River 2003 Expansion Project, Final Environmental Impact Statement/Environmental Impact Report Volume I. CSLC EIR No. 710; FERC/ EIS-0144. June 2002.

US Environmental Protection Agency (EPA). 2002. Federal Register, Vol. 67, No. 151. Rules and Regulations. August 6, 2002.